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BEFORE THE ARIZONA CORPORATION COMMISSION

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AZ CORP COMMISSION
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COMMISSIONERS

KRISTIN K. MAYES, Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RULEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. E-01345A-08-0172 **STAFF'S NOTICE OF FILING DIRECT TESTIMONY ON COST OF SERVICE AND RATE DESIGN**

Staff of the Arizona Corporation Commission ("Staff") hereby files the Direct Testimony on Cost of Service and Rate Design of Staff Witnesses Ralph C. Smith and Frank W. Radigan in the above-referenced matter.

RESPECTFULLY SUBMITTED this 9th day of January, 2009.

Arizona Corporation Commission
DOCKETED
JAN - 9 2009
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DIRECT

TESTIMONY

ON COST OF SERVICE
AND RATE DESIGN

OF

RALPH C. SMITH

FRANK W. RADIGAN

DOCKET NO. E-01345A-08-0172

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN

JANUARY 9, 2009

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
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BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND RESONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01345A-08-0172

DIRECT

SUPPLEMENTAL TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JANUARY 9, 2009

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I. INTRODUCTION

Q. Please state your name, position and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Are you the same Ralph Smith who previously filed direct testimony in this proceeding?

A. Yes.

Q. What did your direct testimony state concerning Demand Side Management ("DSM")?

A. My direct testimony at page 11 stated that:

> "The impacts of Staff's recommendations on the recovery mechanism for Demand Side Management ("DSM") related costs are not yet known and will be addressed by a Staff witness who will present testimony concerning this item in the rate design filing."

Q. How is Staff addressing issues related to DSM at this time?

A. I address an Arizona Public Service Company ("APS") proposed adjustment no. 13. Staff witness Frank Radigan also addresses this issue in his rate design testimony.

II. ADJUSTMENTS TO NET OPERATING INCOME

C-20 DSM Estimated Future Lost Revenue Pro Forma

Q. What has APS proposed as an adjustment to net operating income for DSM and estimated future net lost revenue?

A. As shown on APS witness Ewen's Attachment PME-13 and described in his direct testimony at page 33, APS proposes to reduce test year operating revenue by $16.789 million for 220,696 MWh of lost sales, and to reduce related operating expenses by $1.052 million, for a net reduction to pre-tax operating income of $15.738 million. As explained by Mr. Ewen at page 33 of his testimony:

> "The Company will experience a loss in revenue due to a reduction in customer usage as these [DSM] programs are implemented and become successful. The expected usage reduction from the implementation of programs in 2010 will be approximately 220,696 MWh. The resulting revenue loss is calculated by multiplying the Test Year revenue in cents/kWh, less the Test Year fuel cost in cents/kWh, by these expected MWh reductions. The pre-tax operating revenue adjustment of $15.7 million resulting from these sales adjustments is set forth in the Uncollected Fixed Cost pro forma and is included as Attachment PME-13 and is in SFR Schedule C-2, on page 5, column 13."

Q. Was a similar adjustment proposed by APS and rejected by the Commission in APS' last rate case?

A. Yes. In Docket No. E-01345A-05-0816 et al, APS had proposed a pro forma adjustment for estimated 2006 lost revenues from DSM programs in conjunction with a test year end September 30, 2005, i.e., approximately 1.25 years beyond the test year. In the current case, APS has proposed a pro forma adjustment for estimated 2010 lost revenue from DSM programs in conjunction with a 2007 test year, i.e., three years beyond the test year.

As stated on page 30 of Decision No. 69663:

> APS proposed a Demand Side Management ("DSM") adjustment … to reduce TY revenues by $4,907,000 to reflect Commission

> approved DSM programs. Both Staff and RUCO objected to the pro-forma $4,907,000 revenue adjustment, which reflects a "net lost revenue" or "conservation" adjustment.

As stated on page 31 of Decision No. 69663:

> We agree with Staff and RUCO that APS' pro-forma conservation, or net lost revenue, adjustment to increase (sic) revenues should not be adopted. As testified to by Staff, a mechanism exists for APS to recover a portion of the actual energy efficiency savings from its successful DSM programs. We also agree that neither the adjustment nor its amount is sufficiently known and measurable to reasonably change the cost of service. Further, under the terms of the Settlement Agreement as approved by the Commission, APS is not allowed to recover net lost revenues in this case on a going forward basis.

Q. What is the approximate impact on the revenue requirement?

A. The approximate impact from APS' proposed adjustment no. 13 to the revenue requirement is $15.7 million.

Q. Did Staff make this adjustment in its direct testimony?

A. No. Staff did not make the adjustment because Staff is willing to give APS the opportunity to provide a rational for why Staff should support this recommendation.

Q. How does Staff intend to update this adjustment?

A. Unless APS provides a compelling argument for this adjustment, including a strong argument why a conclusion different than Decision No. 69663 is required, Staff will reverse APS proposed adjust no. 13 when Staff updates its revenue requirement model at the time of Staff's surrebuttal filing.

Q. Does this conclude your supplemental testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

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DIRECT

TESTIMONY

ON THE ISSUES OF REVENUE ALLOCAITON

AND RATE DESIGN

OF

FRANK W. RADIGAN

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JANUARY 9, 2009

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ATTACHMENTS

EXECUTIVE SUMMARY
ARIZONA PUBLIC SERVICE COMPANY
DOCKET NO. E-01345A-08-0172

Based on the improvements in rates of return between the Cost of Service study presented in APS last rate case and this rate case, the numerous changes in rate offerings as well as the numerous rate design changes proposed by the Company in this case, Staff recommends that the APS Cost of Service study not be used as the primary basis for revenue allocation. Instead, the revenue increase should be allocated among rate classes on an equal percentage basis.

With respect to specific schedules, the Company is proposing to freeze the "Series 1" Time-Of-Use ("TOU") rates, *i.e.*, Schedules ET-1 and ECT-1R. Staff supports this for residential customers. This will encourage APS customers to choose either the Company's current "Series 2" TOU rates (ET-2 and ECT-2) or the Company's new proposed ET-SP (Residential Service Time Advantage Super Peak Rate). The "Series 2" TOU rates have a shorter on-peak period than the "Series 1" TOU Rates, the purpose of which is to incent customers to move more load to the off-peak period. The "Series 2" rates been shown to be more effective than the "Series 1" rates in encouraging customers to shift load to off-peak periods, and this shift should be encouraged.

APS is also proposing to modify E-12 (Residential Service – Standard Rate) to include the addition of a fourth and higher priced block rate for customer consumption greater than 3,000 kWh monthly. The intent is to encourage large E-12 customers to both conserve energy and switch to TOU. Staff supports this change because the fourth block is targeted at the largest users (those who could do the most with respect to energy conservation).

APS proposes to increase all Residential Basic Service Charges in order to collect a larger portion of fixed costs through non-energy rates. Some of these increases are large, and could result in rate shock. Therefore, Staff recommends that no Basic Service Charge be increased by more than twice the overall average increase.

The Company is proposing to retain the current discounts for the low-income rate schedules (E-3 and E-4). In these tough economic times, any increase in rates is difficult, but this is especially true for those customers that take service under the support schedules. Staff recommend's that customers on rate schedules E-3 and E-4 maintain their current rates, such that the low-income customers who qualify for electric service under those rates are held harmless from the rate increase. Any revenue shortfall resulting from this recommendation should be recovered from all other rate schedules, in a manner similar to how the overall revenue increase is spread. This result would have a very limited impact on other customers. In addition, Staff recommends that the PSA continue to not apply to low-income customers.

The Company proposes to disaggregate Schedule E-32 (General Service) and E-32 TOU (General Service TOU) into four new rate schedules and to cancel partial requirement rate schedules E-32R (General Service – Partial Requirements Service), E-51 (Classified Service - Partial Requirements Service to Qualified Co-generators greater than 100 kW), and E-55 (Classified Service – Partial Requirements Service to 3,000 kW or greater). The General Service rate schedules are being disaggregated into four new service schedules so as to better price the cost to serve. The partial requirement rate schedules are currently frozen and the services provided under these rate schedules are now covered by Schedules E-56 (Classified Service – Partial Requirements Service) and SC-S (Classified Service – Partial Requirements Solar). These proposals are cost based, reasonable consistent with Decision No. 69663 (June 28, 2007), and the Commission should adopt them.

The Company proposes to freeze Rate Schedule Solar-2 – the rate class where the Company owns and installs a solar power system when it is uneconomic for the customer to install a system on their own. The Company is proposing to freeze the rate because it has outlived its usefulness. Staff supports this change because there are now many more options for customers to purchase solar power systems as opposed to buying them from the Company.

The Company proposes to offer customers two new options for purchasing various percentages (10% and 35%) of their total energy needs through solar power. This supplements the current options provided by Schedule Solar-3 of 100% and 50%. The Company also proposes to provide customers with increased flexibility by allowing them to combine the purchase of power under Schedule Solar-3 with Green Power Block ("GPS-1") and Green Power Percentage ("GPS-2"). The added flexibility of lowering the purchase requirement levels and by combining the solar program with other green power programs is commendable and should be supports.

The Company proposes to add a new Super Peak TOU rate schedule. The Super Peak TOU option has a seven hour on-peak period but adds a super peak price for weekday afternoons from 3 p.m. to 6 p.m. during June, July and August. This option is yet another means to reduce load during the critical peak period. The Company's existing TOU rate options have been effective in encouraging customers to move load to off-peak periods. The Super Peak TOU option, however, incents the customer to a few select hours during the Company's peak months. This Super Peak TOU could prove to be an even more effective tool than the existing TOU rate schedules.

The Company also proposes to add a new Critical Peak Pricing ("CPP") program. This is another positive step to control peak load. It is targeted to customers that can most likely shed load; it provides an adequate discount to encourage participation; and, it is limited in scope so that it can be controlled, evaluated, and improved before it is offered to all customers. Staff believes that there are two improvements, however, that should be made to the program. First, to successfully test how customers react to the need for a demand response, one must have actual data. Staff would therefore change the tariff language to state that the Company will invoke a <u>minimum</u> of 6 CPP Events and a maximum of 18 CPP Events per calendar year. Second, the Company's proposal to limit participation to 100 is too low given that it is proposing to offer the program to seven different service classes. Staff recommends that the number of participants be increased to 200.

The Company proposes to modify the Environmental Improvement Surcharge ("EIS") to reduce regulatory lag. This proposal should be rejected. The Company has presented the same arguments that it made in the last case, and the Commission has already ruled on the issue.

The Company proposes to modify the Transmission Cost Adjustor ("TCA") to operate as an automatic rate adjustor whenever FERC modifies the open access transmission rate. This proposal should also be rejected as unnecessary and unwarranted.

The Company seeks to modify Service Schedules 1, 4, 5, 8, 10 and 15 in a number of respects. These changes provide clarifications to existing provisions of the schedules. Therefore, Staff would recommend their adoption by the Commission.

In Staff witness Smith's accompanying supplemental testimony, he discusses an APS operating income adjustment related to Demand Side Management and estimated future net revenue losses that APS attributes to DSM. My testimony relates to the policy aspects of the DSM recovery mechanisms and describes how APS is compensated for performing DSM through a performance incentive mechanism that is designed to reward APS only when its DSM programs are successful and result in energy or demand savings.

INTRODUCTION

Q. Please state your name, position and business address.

A. Frank W. Radigan. I am a principal in the Hudson River Energy Company, a consulting firm providing services to the utility industry and specializing in the fields of rates, planning, and utility economics. My office address is 237 Schoolhouse Road, Albany, New York 12203.

Q. Have you previously provided testimony in this proceeding?

A. Yes, Staff provided testimony on the issue of the Demand Side Management Adjustor Mechanism and the Impact Fee which was filed on December 19, 2008. That testimony summarized my qualifications and experience as well.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. Have you previously testified before the Commission?

A. Yes. I have testified before the Commission previously on three occasions. I testified before the Commission in the most recent UNS Electric, Inc. rate case (Docket No. E-04204A-06-0783), the most recent Tucson Electric Power Company rate case (Docket No. E-01933A-07-0402), and the most recent Southwest Gas Company rate case (Docket No. G-01551A-07-0504).

Q. What is the purpose of the testimony you are presenting?

A. The purpose of my testimony is to address Staff's review of the Cost of Service study, the allocation of the revenue increase amongst service classes, the proposed rate design, and proposed changes to various service schedules, including the proposed changes to the Environmental Improvement Surcharge and the Transmission Cost Adjustor.

Q. Could you please summarize your testimony?

A. Yes, based on the improvements in rates of return between the Cost of Service study presented in APS last rate case and this rate case, the numerous changes in rate offerings as well as the numerous rate design changes proposed by the Company in this case, Staff recommends that the APS Cost of Service study not be used as the primary basis for revenue allocation. Instead, the revenue increase should be allocated among rate classes on an equal percentage basis.

With respect to specific schedules, the Company is proposing to freeze the "Series 1" Time-Of-Use ("TOU") rates, *i.e.*, Schedules ET-1 and ECT-1R. Staff supports this proposal because it will encourage APS customers to choose either the Company's current "Series 2" TOU rates (ET-2 and ECT-2) or the Company's new proposed ET-SP (Residential Service Time Advantage Super Peak Rate). The "Series 2" TOU rates have a shorter on-peak period than the "Series 1" TOU Rates, the purpose of which is to incent customers to move more load to the off-peak period. The "Series 2" rates been shown to be more effective than the "Series 1" rates in encouraging customers to shift load to off-peak periods, and this shift should be encouraged.

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The Company is proposing to retain the current discounts for the low-income rate schedules (E-3 and E-4). In these tough economic times, any increase in rates is difficult, but this is especially true for those customers that take service under the low-income schedules. Staff recommends that customers on rate schedules E-3 and E-4 have their rates remain at current levels, such that the low-income customers who qualify for electric service under E-3 and E-4 are held harmless from the rate increase. Any revenue shortfall resulting from this recommendation should be recovered from all other rate schedules, in a manner similar to how the overall revenue increase is spread. This result would have a very limited impact on other customers.

The Company proposes to disaggregate Schedule E-32 (General Service) and E-32 TOU (General Service TOU) into four new rate schedules and to cancel partial requirement rate schedules E-32R (General Service – Partial Requirements Service), E-51 (Classified Service - Partial Requirements Service to Qualified Co-generators greater than 100 kW), and E-55 (Classified Service – Partial Requirements Service to 3,000 kW or greater). The General Service rate schedules are being disaggregated into four new service schedules so as to better price the cost to serve. The partial requirement rate schedules are currently frozen and the services provided under these rate schedules are now covered by Schedules E-56 (Classified Service – Partial Requirements Service) and SC-S (Classified Service – Partial Requirements Solar). These proposals are reasonable and consistent with Decision No. 69663 (June 28, 2007).

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The Company proposes to offer customers two new options for purchasing various percentages (10% and 35%) of their total energy needs through solar power. This supplements the current options provided by Schedule Solar-3 of 100% and 50%. The Company also proposes to provide customers with increased flexibility by allowing them to combine the purchase of power under Schedule Solar-3 with Green Power Block ("GPS-1") and Green Power Percentage ("GPS-2"). The added flexibility of lowering the purchase requirement levels, and by combining the solar program with other green power programs, is commendable. Staff recommends the adoption of these changes.

The Company proposes to add a new Super Peak TOU rate schedule. The Super Peak TOU option has a seven hour on-peak period but adds a super peak price for weekday afternoons from 3 p.m. to 6 p.m. during June, July and August. This option is yet another means to reduce load during the critical peak period. The Company's existing TOU rate options have been effective in encouraging customers to move load to off-peak periods. The Super Peak TOU option, however, incents the customer to shift load during a few select hours in the Company's peak months. This Super Peak TOU could prove to be an even more effective tool than the existing TOU rate schedules.

The Company also proposes to add a new Critical Peak Pricing ("CPP") program. This is another positive step to control peak load. It is targeted to customers that can most likely shed load; it provides an adequate discount to encourage participation; and it is limited in scope so that it can be controlled, evaluated, and improved before it is offered to all customers. Staff believes that there are two improvements, however, that should be made to the program. First, to successfully test how customers react to the need for a demand response, one must have actual data. Staff would therefore change the tariff language to state that the Company will invoke a <u>minimum</u> of 6 CPP Events and a maximum of 18 CPP Events per calendar year. Second, the Company's proposal to limit participation to 100 is too low given that it is proposing to offer the program to seven different service classes. Staff recommends that the number of participants be increased to 200.

The Company proposes to modify the Environmental Improvement Surcharge ("EIS") to reduce regulatory lag. This proposal should be rejected. The Company has presented the same arguments that it made in the last case, and the Commission has already ruled on the issue. The Commission set a fixed surcharge amount instead of adopting an adjustor mechanism.

The Company proposes to modify the Transmission Cost Adjustor ("TCA") to operate as an automatic rate adjustor whenever FERC modifies the open access transmission rate. Staff cannot support the proposal.

The Company seeks to modify Service Schedules 1, 4, 5, 8, 10 and 15 in a number of respects. These changes are generally minor and mostly provide clarifications to existing provisions of the schedules. Therefore, Staff would recommend their adoption by the Commission.

Finally, Staff discusses the rate design aspects of the Demand Side Management ("DSM") lost revenue recovery mechanism. As addressed in the supplemental testimony of Staff witness Ralph Smith, unless APS provides a compelling argument for its adjustment for lost revenue due to DSM, Staff will reverse APS' adjustment when Staff updates its revenue requirement model at the time of Staff's surrebuttal filing. Utilities can be compensated in a variety of ways for performing DSM and this Company already has a compensation mechanism which was adopted as part of a comprehensive settlement.

COST OF SERVICE AND REVENUE ALLOCATION

Q. Could you please summarize APS' proposals with respect to its Cost of Service study and revenue allocation?

A. Yes, APS performed an embedded Cost of Service study using the twelve-month period ending September 30, 2007. (Rumolo Pre-Filed Testimony ("PFT"), page 14). APS did not perform a detailed marginal Cost of Service study. (Rumolo PFT, page 16). However, APS used marginal cost concepts to develop seasonal and time-of-use cost differentials. (Rumolo PFT, page 16). In performing the Cost of Service study, the Company analyzed costs by function, classified them as to cost causality, and allocated them by jurisdiction (Federal or State), service class, and rate schedule. (Rumolo PFT, pages 15-19).

In the last APS rate case, there was considerable disagreement between the parties about how to allocate the costs of owning and operating the generating plants and associated energy. Given that these costs are approximately 70% of total costs, the choice of allocation method will have a considerable impact on the Cost of Service results. In Decision No. 69663, the Commission directed APS to use an energy-weighted method to allocate production demand costs. (Decision No. 69663, page 71). In its Application the Company used the Average and Excess Demand ("AED") Method, which is a widely accepted energy allocation method. (Rumolo PFT, page 20). The AED method allocates a portion of production costs based on a customer class' peak demand contribution and then allocates the balance on that class' energy-based or average demand contribution. The

AED method recognizes that production facilities provide both demand and energy related functions.

Also in the last APS rate case, it was suggested that an hourly allocation method be used to allocate fuel and purchased power costs. (Decision No. 69663, page 71). The hourly energy allocation method examines customer class hourly load shapes and hourly energy prices to come up with a weighted energy cost. (Rumolo PFT, page 21). For example, a customer class that uses more of its energy during peak summer hours should be allocated higher average fuel and energy costs than a customer class whose energy consumption is more off peak.

Thus, the Company's Cost of Service study has used a widely accepted methodology to allocate production costs and has addressed the means to allocate energy costs to service classes as suggested by parties in the last case.

Q. What is typically the end result of a Cost of Service study, and how is it used in developing rates?

A. The end result of performing a Cost of Service study is to provide a rate of return for each customer class and to functionalize, classify, and allocate costs. The rate of return by class is helpful to determine if a service class is providing too little or too much in revenues. For example, if the General Service class has a rate of return of 12% and if the overall rate of return is 10%, then that service class should receive a smaller than average increase in rates. Dividing a class rate of return by the overall rate of return provides a Rate of Return Index ("ROR Index"), which is a helpful tool for comparing the rate of return for each service class with the overall rate of return. In the example above, the General Service Class would have an ROR index of 1.2 (12%/10%). While this provides a useful benchmark for analyzing the Company's proposed rate class increases, it is only one factor the Commission should consider in setting rates.

Q. What were the results of APS' Cost of Service study?

A. The results of the Company's Cost of Service study, including the ROR index for each service class, are presented in the table below:

Service Class	Rate of Return	ROR Index
Residential	2.85%	0.75
General Service	5.04%	1.33
Water Pumping	6.92%	1.82
Street Lighting	-0.03%	-0.01
Dusk to Dawn	6.61%	1.74
Total	3.79%	1.00

Q. What did APS state concerning its application of those results?

A. Company witness Rumolo states that the Cost of Service study was a major input for designing the Company's proposed rates. (Rumolo PFT, page 15). When asked in discovery to explain how the results of the Cost of Service study were used to allocate rates, the Company responded that its proposed revenue allocation does not bring customer class rates completely in line with costs, but rather moves in that direction. In its response, the Company also provided a table that sets forth a comparison between the Cost of Service revenue deficiency for each rate class and the proposed revenue increase. The response and table are provided as Exhibit FWR-2.

Q. What does your analysis indicate?

A. A comparison of the results of the Cost of Service study and the Company's proposed revenue allocation shows that the Company did consider the results of its Cost of Service study, but only to a small degree. For example, given APS' overall requested increase of 16.99%, the Cost of Service study indicates that the General Service Class should receive an 11.6% increase, but the Company recommends that the class receive a 16.74% increase. For the Residential Service Class, the Cost of Service study indicates that the class should get a 21.7% increase, but the Company recommends that the class get a 17.27% increase. The disparity between the results of the Cost of Service study and the recommended revenue allocation does not stop at the service class level but also extends to individual rate schedules as well. For example, the Cost of Service study indicates that General Service Rate Schedule E-20 should receive a 54.3% increase, while the Company is recommending a 20.2% increase. For Residential Rate Schedule E-12, the Cost of Service study indicates that the class should receive a 9.5% increase, but the Company is recommending a 16.43% increase. (It should be noted that these differences are not due to the PSA revenue (fuel) component of the total 16.99% increase requested by APS).

Q. Has the Company indicated that it considered other objectives in its proposed revenue allocation besides the Cost of Service study results?

A. Yes, in its response to Staff data request 22.7, the Company explained that it considered other objectives in the revenue allocation process include preserving rate stability; avoiding rate shock for any rate class; reducing, but not eliminating, the return differential between General Service and Residential Revenue Classes; and preserving consistency between TOU rates and other rate options.

Q. Do you agree that other objectives should be considered in the revenue allocation process?

A. Yes, reviewing the results of the most recent Cost of Service study is just one of many considerations to be used when deciding how to allocate revenues. One should also look at how the Company is proposing to use the Cost of Service Study results, the results of past studies, and also changes being proposed in the rate schedule offerings and rate design.

Q. Has the Company made progress in moving rates closer to the rate of return index?

A. Yes. The table below shows the results of this Cost of Service study and the Cost of Service study from the last rate case (using the Company's proposed allocation method)[1].

	Last COSS		**Current COSS**	
Service Class	**Rate of Return**	**ROR Index**	**Rate of Return**	**ROR Index**
Residential	1.38%	0.53	2.85%	0.75
General Service	4.12%	1.59	5.04%	1.33
Water Pumping	3.72%	1.44	6.92%	1.82
Street Lighting	1.61%	0.62	-0.03%	-.01
Dusk to Dawn	5.28%	2.04	6.61%	1.74
Total	2.59%	1.00	3.79%	1.00

[1] The results of the Cost of Service study from the last APS rate case were taken from Docket No. E-01345A-05-0812 – APS Exhibit No. 70, Rumolo Rebuttal, p. 9, and Attachment DJR-IRB)

As can be seen, there has been a considerable shift in the ROR indices for most of the service classes with considerable movement for the Residential and General Service Classes. For the Residential Class, the ROR index went from 0.53 to 0.75, which indicates that its rate of return relative to the overall rate of return has improved sharply. For the General Service Class, the ROR index has decreased from 1.59 to 1.33, which indicates movement from a position of overpaying relative to the overall average rate of return. These changes could be the result of the revenue allocation adopted in the Company's last rate case or due to changing cost causality. For example, between 2004 (the test year in the last Cost of Service study and 2007, residential sales and revenues grew by 20% and 45%, respectively. This compares to total Company growth of 14% and an increase in revenues of 40%. While this growth may not totally explain the improvement in the ROR Index for the Residential Class, it cannot be denied that improvement did occur.

Q. Could you please explain the issue of how load shapes should be considered in the revenue allocation process?

A. Yes. In response to a Staff discovery request, Staff obtained 2007 hourly load data for each rate schedule[2]. Based on the load data for the peak day (08/13/2007), Staff then developed load shapes for the Company as a whole and for each rate schedule. The graph below shows the load shape for the peak day in 2007. As can be seen, the Company peaked at 5 p.m. with a very pronounced peak.

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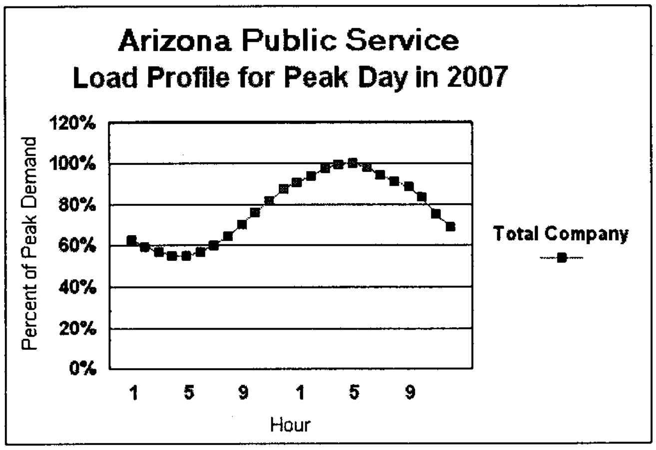
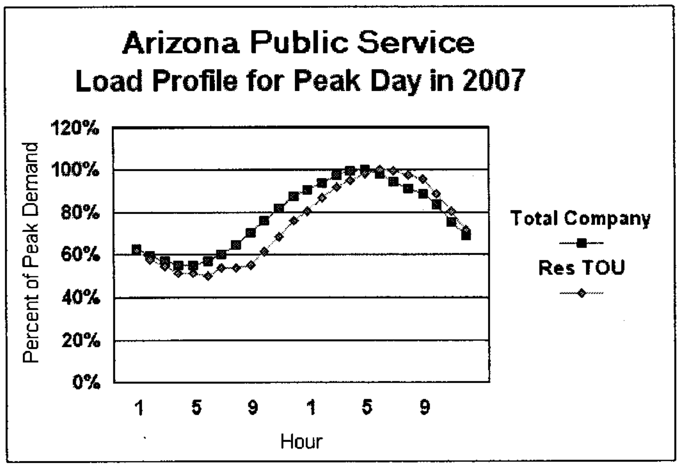
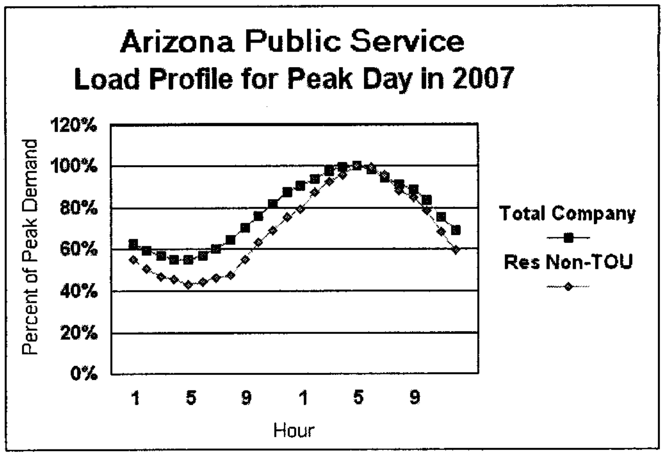
[2] Responses to Staff 22.6 and 22.10 which are too voluminous for attachment.



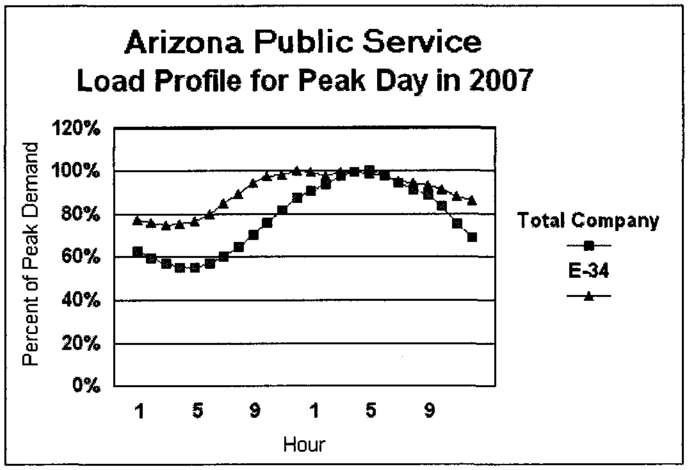
Comparing the load profile of individual rate schedules to the Company load profile is also a useful exercise when one tries to evaluate the effectiveness of the rate design offerings being made. The two graphs below show the load profiles of the residential TOU and the residential non-TOU rate schedules.

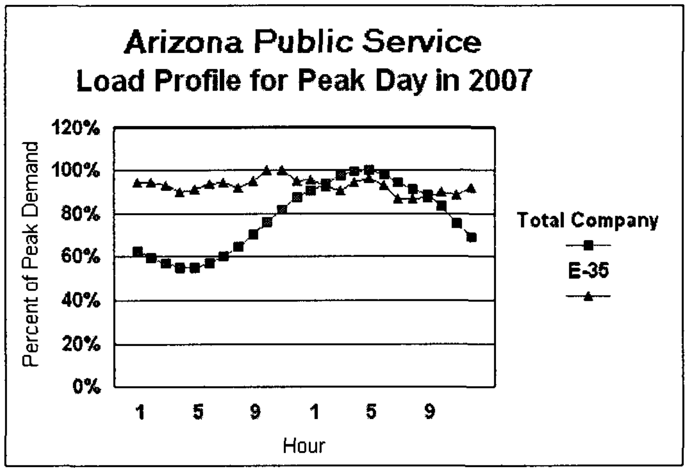




As can be seen from the graphs, the non-TOU customers peak when the Company overall load peaks and do so with an even more pronounced peak than the Total Company. The TOU customers also have a significant amount of load during the peak period, however, when one compares the load profile of the TOU customers to the non-TOU customers, it is clear that the TOU customers have reacted positively to the price signals and have moved load to the off-peak period.

As shown on the graphs below, this same reaction to price signals occurs for the General Service customers as evidenced by the load profiles of rate schedules E-34 (Extra Large General Service) and E-35 (Extra Large General Service TOU). The TOU rate schedules have moved a significant amount of load away from the peak period in response to price signals.





Q. Are there any other factors that should be considered in the review of the results of the Cost of Service study and the allocation of revenues?

A. Yes. The change in the rate offerings being made by the Company also needs to be considered.

Q. What changes is APS proposing and how should they be considered?

A. Two Residential rate schedules are being eliminated (Rate Schedules E-10 and EC-1) and these customers have to elect another rate schedule. The partial requirement rate schedules E-32R (General Service – Partial Requirements Service), E-51 (Classified Service - Partial Requirements Service to Qualified Cogenerators greater than 100 kW), and E-55 (Classified Service – Partial Requirements Service to 3,000 kW or greater) are all being cancelled, and these customers will be moved to other rate schedules (E-56 and SC-S). The "Series 1" TOU rate schedules (ET-1 and ECT-1R) discussed previously are being frozen, and it is anticipated that these customers will migrate to other rate schedules. Together, these changes impact rate schedules that currently provide 31% of the Company's revenues. Customers subscribed to all of these schedules in the test year will react in some way to the cancellation and/or freezing of the schedules. Given the large amount of revenue involved, changing customer behavior could have a significant impact on the results of the Cost of Service study. In addition, the Company is proposing to disaggregate the E-32 (General Service) and E-32 TOU (General Service TOU) Rate Schedules into four new rate schedules. The customers under these rate schedules provide 40% of the current revenues. We do not know how these customers will react to the new rates that they will be paying. In summary, these significant changes in rate offerings could have a dramatic impact on the results of the Cost of Service study and indicate that it should not be exclusively relied upon as a means to allocate revenues in this case.

Q. What do you recommend?

A. After considering all of the factors discussed above, Staff recommends that any increase in revenues be allocated across the board on an equal percentage basis. As Staff will discuss in more detail below, Staff recommends that customers on Rate Schedules E-3 (Energy Support) and E-4 (Medical Equipment Support Program) receive no increase in rates. Any resulting revenue shortfall should be recovered from all other rate schedules on an equal percentage basis. Staff's proposed revenue allocation is shown on Exhibit FWR-3.

Q. Were there any exceptions to the recommended revenue allocation that you recommend besides the E-3 and E-4 rate schedules?

A. No, but there was a refinement. The Company has nine rate schedules that are tied to the E-32 (General Service) rate schedule. As noted in the testimony of Company Witness Delizio, the rates were not designed to adhere to strict Cost of Service but are necessarily tailored to the various rate schedules (Delizio PFT, pages 28-29). In other words he designed rates by customer size and voltage level first (i.e. by rate differential). Thus, the rates of the E-32 non-TOU rates are themselves tied together because of the rate differentials between voltage levels. The E-32 TOU rates were similarly designed. (Delizio PTF, page 32). As shown on Exhibit FWR-3, the Company's proposed revenue allocation is different for the individual rate schedules (e.g., E-32 > 401 kW rate schedules receives a 15.7%, while the increase for E-32 0-20 kW rate schedule receives an 18.7% increase).

The interrelationship of rate schedules presents an issue with respect to revenue allocation. If one applies an equal percentage increase to each rate schedule, the rate differentials between the voltages and customer sizes change. If one tries to keep the rate differentials between rate schedules, the percentage increase to each rate schedule changes. In my revenue allocation to the E-32 rate schedules, the directive by the Commission in Decision No. 69443 was to disaggregate into more service classes delineated by size. Thus, Staff felt keeping the rate differential was more important than keeping the percentage increase equal between rate schedules within E-32. The easiest way to do that was to make sure that as a group the E-32 General Service Class was given the same overall average increase as the Company and maintained rate differentials.

RESIDENTIAL RATE SCHEDULES

Q. Would you please give a summary of the existing Residential Rate Schedules that APS offers?

A. In the test year, APS had nine Residential Rate Schedules – four TOU rate schedules (Schedules ET-1, ECT-1R, ET-2, and ECT-2), one inclining block rate schedule (Schedule E-12), two rate schedules for special assistance (Schedule E-3 and Schedule E-4), and two rate schedules (E-10 and EC-1) that were eliminated by the Commission in Decision No. 69663.

For Schedules E-10 and EC-1, customers were given a one-year transition period, which expired on July 1, 2008, to select another rate. For rate design purposes, the Company has assumed that the E-10 customers all chose the E-12 rate and that the EC-1 customers all chose the ECT-1R rate schedule.

Q. What does the Company propose in this case with respect to residential rate offerings?

A. The Company proposes to freeze: the "Series 1" TOU rate schedules (Rate Schedule ET-1 and Rate Schedule ECT-1R) so that they will not be available to new customers or to existing customers who switch service locations. The "Series 2" TOU rate schedules (Rate Schedule ET-2 and Rate Schedule ECT-2) will serve as the primary TOU rate offerings. The Company believes that the "Series 2" TOU rates provide a better opportunity for customers to shift usage to the off-peak hours and, thereby, reduce their bills. (Delizio PFT, page 26).

The "Series 1" rates, ET-1 and ECT-1R, have a 12-hour on-peak period from 9 a.m. to 9 p.m. weekdays. In July 2006, APS introduced the "Series 2" rates, Schedules ET-2 and

ECT-2, to encourage customers to shift more load to the off-peak period, especially during the summer months. The "Series 2" rates have a 7-hour on-peak period from noon to 7:00 p.m. weekdays. In addition, the all-energy rate, Schedule ET-2, has a summer on-peak price that is four times as high as the off-peak price. The Company believes that the "Series 2" TOU rates, due to the shorter on-peak period (and longer lower price off-peak periods), provide a better opportunity for customers to shift usage to the off-peak hours and thereby reduce their bills. (Delizio PFT, page 26).

Company Witness Miessner also proposes to add a new Rate Schedule ET-SP. The proposed rate would be similar to rate ET-2, with a 7-hour on-peak period, but will add a Super Peak price for weekday afternoons from 3:00 p.m. to 6:00 p.m. during June, July and August. The summer off-peak price is discounted to off-set the higher Super Peak price. The customer has the opportunity to have lower monthly bills by reducing load during either the on-peak or Super-Peak periods, or both. (Miessner PFT, page 9).

If APS' proposed residential rate schedules were adopted, APS would have six rate offerings available to new customers: four standard rate offerings, E-12, ET-2, ECT-2 and ET-SP; and two low-income programs, E-3 and E-4.

Q. Please summarize other significant rate design issues being proposed.

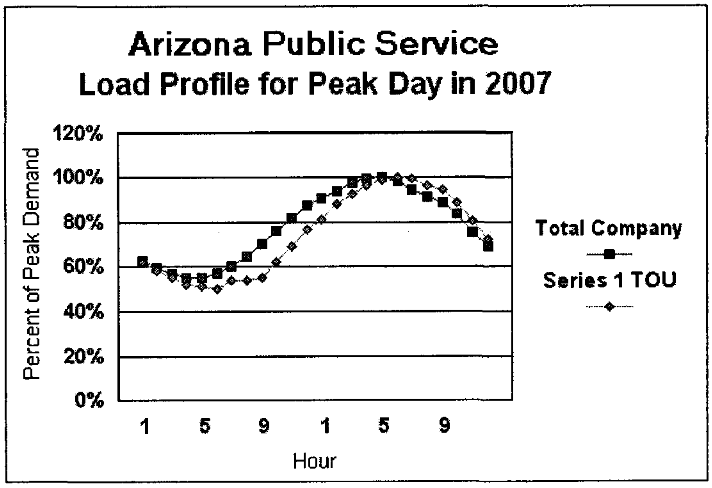
A. In addition to the introduction of the Super Peak TOU rate, there are several other rate design changes being proposed by the Company. The Company is proposing a fourth block for E-12. This higher priced block rate is for customer consumption greater than 3,000 kWh per month. As explained by Company witness Delizio, the intent of this new block is to encourage energy conservation for the Company's largest residential users. The change would also provide an additional price incentive for such customers to switch to a TOU rate. (Delizio PFT, page 3).

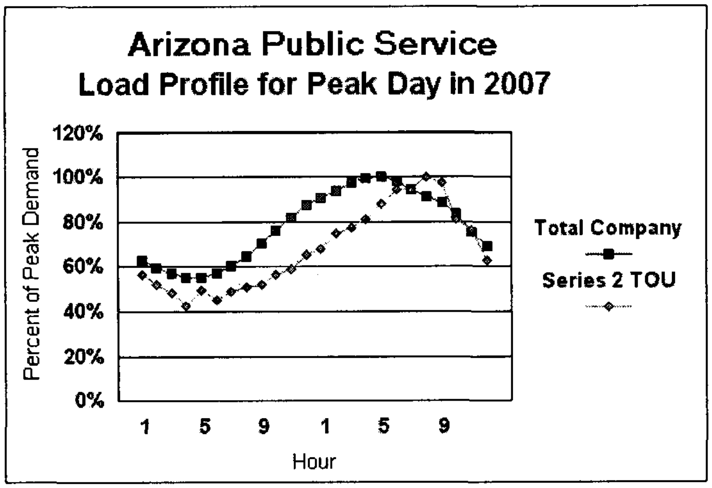
The Company also proposes to continue the discounts to the low-income rate schedules, E-3 and E-4.

The only other significant proposed rate design changes proposed are increases to the bundled Basic Service Charges for all Residential Rate Schedules between about 2¢ to about 9¢/day to better reflect the fixed costs associated with customer connection to APS' system. The increase of 2 ¢/day applies to all but the E-12 Rate Schedule and results in a 3.8% increase in the Basic Service Charge. The increase of 9 ¢/day for the E-12 Rate Schedule results in a 36% increase in the charge.

Q. Please comment on the Company's proposed changes to the rate schedules.

A. The majority of the proposed changes are reasonable and should be approved. The Company's proposed fourth block to E-12 and the new TOU rate offerings are a good step forward in providing customers with appropriate price signals. Although the current "Series 1" TOU rates have been somewhat effective in encouraging customers to shift to the off-peak period, the on-peak period for this series is excessively long. As evidenced by the graphs below, load research shows that rate structure for the "Series 2" TOU is more effective in encouraging customers to shift load away from the time of system peak. Thus, on a going forward basis, the "Series 2" TOU rates are the better choice.





Some changes proposed by the Company, however, do not go far enough. TOU rates and inclining block rates do not need to be separate offerings. In the recent Tucson Electric Power Case (Docket No. E-01933A-07-0402), the parties agreed to TOU rate offerings that also had inclining block rates. APS should be directed to file an inclining block rate schedule for all of its Residential TOU rate schedules.

In addition the Company is proposing to retain the current discounts for the low-income rate schedules (E-3 and E-4). In these tough economic times, any increase in rates is difficult, but this is especially true for those customers that take service under these schedules. However, Staff recommends that all low-income customers retain their current rates. In addition, Staff recommends that the PSA continue to not apply to low-income customers.

The 36% increase in the E-12 Basic Service Charge proposed by APS should be rejected. While the proposed rate of $0.343 per day is less than the cost-based rate of approximately $0.50 per day, the rate impact is unacceptable, especially under Staff's proposed revenue increase. Staff proposes that the increase in the Basic Service Charge be limited to no more than twice the overall average increase (in this case, 19.42% for a basic service charge of $0.302 per day).

GENERAL SERVICE RATE SCHEDULES

Q. Would you please discuss the significant rate design changes that APS is proposing for the General Service Rate Schedules?

A. Yes. First, as an outcome of the Company's last rate case and as directed in Decision No. 69663, the Company is proposing to disaggregate rate schedule E-32 into several new rate schedules based on customer size. The Company proposes to replace the two size categories (Tier 1 (0-20 kW) and Tier 2 (greater than 20 kW)) with four sizes categories (E-32 XS (0-20 kW); E-32 S (21-100 kW); E-32 M (101-400 kW); and E-32 L (greater than 400 kW)). The proposed rate structure for E-32 XS would be similar to the current E-32 Tier 2 rate. The proposed rate structure for E-32 S, E-32 M, and E-32 L would be similar to the current E-32 greater than 20 kW rate. The Company believes that this modification will provide rates that are better tailored to the customers in these size categories, and will result in revenues that are more aligned with costs (Delizio PFT, page 28). This is a reasonable change. With increasing usage, the service size and voltage level generally also increase. Accordingly, customer size is one good indicator of different usage characteristics and cost to serve.

Second, the Company currently offers several time-of-use rates for General Service and Water Pumping customers (Rate Schedule E-32 and Rate Schedule E-35). As explained by Company witness Delizio, the Company is proposing to disaggregate rate schedule E-32 TOU into several new rate schedules based on the same customer size categories proposed for Rate Schedule E-32. The current rate schedule E-32 TOU is separated into two size categories: Tier 1 (0-20 kW) and Tier 2 (greater than 20 kW). The proposed rate schedules will be divided into four size categories: E-32 TOU XS (0-20 kW); E-32 TOU S (21-100 kW); E-32 TOU M (101-400 kW); and E-32 TOU L (greater than 400 kW). The four new general service TOU rate schedules were designed with the same methodology and with the same objectives as previously described for E-32. (Delizio PTF, page 31). As shown above, customers react positively to TOU rates. Tailoring the rate offerings to better suit both size and cost to serve should result in even more positive behavior.

Third, Rate Schedules E-34 and E-35 are the rate schedules that are applicable to APS' largest customers. As described in the testimony of Company witness Delizio, the Basic Service Charge for both rate schedules has been increased to better reflect the Cost of Service, and language was added to the rate schedules to broaden the application of the demand charge discount for Military Base customers taking primary service and served from a dedicated distribution feeder. (Delizio PFT, page 32). The Company states that this change should result in both Luke Air Force Base and the Yuma Marine Corps Air Station being served on the same footing with regard to their electric service. Discounts for dedicated services help customers avoid paying for the carrying costs for all distribution feeders on the system. This change is fair to both the Company and customers and should be accepted.

Fourth, given that these customers may at some point take direct access, the Company added a provision to the E-34 and E-35 rate schedules to require the customer to compensate the Company for the costs of additional third-party transmission service that is required solely to provide service to a specific customer or customers. (Delizio PFT, page 33). This provision only applies in those instances where the arrangements can be directly attributable to a specific customer or customers. Passing direct costs on to those customers, who elect to take service from others, minimizes the risk of cross subsidization.

CANCELLING PARTIAL REQUIREMENTS RATE SCHEDULES

Q. Why is the Company proposing to cancel Partial Requirement Rate Schedules E32-R, E-51, and E-55?

A. The Company proposes that the existing Partial Requirement Rate Schedules, E-32R, E-51 and E-55, which are currently frozen, be cancelled. (Delizio PFT, page 30). This was an issue in the last APS rate case. In Decision No. 69663, the Commission adopted the Company's request to freeze Partial Requirement Rate Schedules E-32R, E-51, and E-55 and to cancel the rate schedules in this case. Company witness Delizio states that the services provided under these rate schedules are now covered by Schedules E-56 and SC-S. Mr. Delizio states that there are a total of four customers served under these rate schedules (two on E-32R, one on Schedule E-51, and one in Schedule E-55). The Company believes that these customers can migrate to Schedule E-56 and Schedule SC-S with minimal (if any) adverse impact on their bill.

Q. Do you agree with these Company-proposed changes?

A. Yes. As the number of customers is small, the current classes are frozen, and there are other rate schedules available to service them, the Company's proposal to consolidate the number of rate offerings is reasonable.

<u>**SOLAR POWER AND GREEN POWER MODIFICATIONS**</u>

Q. How does the Company propose to modify its Solar Power offerings?

A. The Company proposes to freeze the Solar-2 rate to customers currently served under its provisions. (Delizio PFT, page 34). Under Solar-2, the Company offers power generated by Company-owned and maintained solar electric systems for customers who cannot be economically connected by extension of the Company's distribution system. The systems typically will include a photovoltaic module array, the module array mounting structure, the control structure, the control equipment, any necessary wiring, batteries, and any other equipment necessary to provide service that meets all applicable building and safety codes at a mutually agreed upon point of delivery. The Company owns, maintains, and makes necessary repairs to the solar electric system. In his testimony, Company witness Delizio states the belief that Solar-2 is no longer necessary since customers may be eligible to participate in APS' Solar Partners Initiative Program and may be eligible for federal and state tax incentives not currently available to utilities. (Delizio PFT, page 34). There are currently only two customers served on Solar-2.

In an effort to encourage greater customer participation in solar power, the Company also proposes changes to Solar-3. Solar-3 is a pilot program, and service under the rate schedule provides all or a portion of the customer's service from solar electric generating systems producing AC electricity and delivered via APS' electric power grid. Customers pay the Company the cost of purchasing the solar power and are credited the avoided cost value of the energy. In short, a premium is paid for taking solar power, but customers volunteer for the program in order to promote the technology. Currently, customers taking service under this rate schedule must have at least 50% or 100% of their energy supply provided from solar power. In addition, customers taking service under this rate schedule currently cannot combine it with other solar or green power options.

In this case, the Company is proposing two new subscription options: 10% and 35% with respect to the amount of the customer's power coming from solar power. These two new subscription options supplement the current 100% and 50% options. (Delizio PFT, page 34). The Company hopes that these additional choices will increase customer participation in solar power. (Delizio PFT, page 35). In addition, the Company has upgraded its billing system capability so that it can now offer customers the option to supplement energy usage by combining Solar-3 with either Green Power Service Schedule (GPS-1 or GPS-2). The Company states that this ability to "mix and match" will hopefully increase participation in all three rate schedules.

Q. Do you agree with these Company-proposed changes?

A. Yes. Staff supports the change to freeze Solar-2 because there are now many more options for customers to purchase solar power systems as opposed to buying them from the Company. Staff also supports the new subscription options for Solar-3. The added flexibility of lowering the purchase requirement levels and combining the solar program with other green power programs is commendable and should be supported.

DEMAND RESPONSE PROGRAMS

Q. Please comment on the Company's Demand Response Pricing Program Proposals.

A. Demand Response Programs are designed to provide incentives to customers to reduce their load. The need to reduce load may be the result of high prices, market conditions, or threats to system reliability. Demand Response can result in immediate savings of variable supply costs, and can displace the need to build additional transmission or generation capacity. Demand Response programs can be pricing programs, where the customer faces high prices during critical periods in exchange for lower prices during other time periods, or quantity programs, where the customer agrees to curtail load during critical periods. APS states that Time-of-Use rates and Critical Peak Pricing are two examples of Demand Response Programs. In Decision No. 69663, the Commission ordered the Company to conduct a study on demand response and to submit one or more programs based upon that study. (Decision No. 69663, page 154). The Commission also ordered the Company to consider a Critical Peak Pricing ("CPP") Program and offer it in its next rate filing. (Decision No. 69663, page 145).

Company Witness Miessner presents the Company's position on Demand Response Pricing Programs, which include Time-Of-Use Rates ("TOU"), Critical Peak Pricing ("CPP"), Real Time Pricing ("RTP"), and other concepts. Mr. Miessner also presents the research that the Company is conducting to formulate a Demand Response Strategy.

Based on this research, APS has concluded the following:

- Several Demand Response options, including TOU, CPP, and RTP, have resulted in moderate to high levels of load reduction during summer peak periods, depending on the particular utility's customer profile.

- TOU is available for more summer hours, compared to CPP, which may provide more consistent load reduction over time and have a greater impact on reducing capacity costs.
- TOU rates are likely to have a higher customer acceptance compared with CPP and RTP for residential customers and are typically less expensive to implement and operate compared with CPP and RTP.
- CPP programs are "dispatchable" and could provide load response during the most critical hours. However, CPP may appeal to a select group of customers that have the ability to reduce their usage on short notice.
- RTP programs are better targeted to commercial and industrial customers who can manage their usage to reduce the risks of being billed according to hourly energy prices.
- RTP programs are better suited for utilities with highly variable hourly energy prices and can have significant implementation costs, but are generally less effective in reducing peak load than either CPP or TOU. (Miessner PFT, page 7).

Based on these conclusions, APS is recommending a new residential TOU rate, which provides higher peak price signals during the highest summer peak hours. (Miessner PFT, page 8). The Company is also recommending that a CPP program be offered to General Service customers. The program will test the potential load reduction, customer acceptance, and implementation cost issues. The Company is not recommending a RTP program at this time because it does not believe that this option is likely to be as beneficial to APS and its customers compared to other Demand Response Pricing options.

Super Peak TOU Pricing

Q. Please summarize the proposed Residential TOU Rate with the Super Peak Price.

A. As explained by Company witness Miessner, the Company is proposing a new residential TOU rate with a Super Peak Price. The rate will be similar to rate ET-2, with a 7-hour on-peak period, but will add a Super Peak Price for weekday afternoons from 3:00 p.m. to 6:00 p.m. during June, July and August. The price for the Super Peak period is raised to $0.4895 per kWh from the normal price of $0.2349 per kWh. The summer off-peak price will be discounted more than the off-peak price for the ET-2 rate in order to off-set the higher Super Peak Price and to give customers the opportunity to lower monthly bills by reducing load during either the on-peak and/or Super-Peak Period. (Miessner PFT, page 9).

Q. Is the Company's proposal reasonable?

A. Yes, the Company's proposal to add a new Super Peak TOU option is yet another means by which to alleviate load during the critical peak period. As discussed before, the Company's existing TOU rate options have been effective in encouraging customers to move load to off-peak periods. The Super Peak TOU option, which concentrates the financial incentive in a select few hours during the peak months, could prove an even more effective tool. The off-peak price for the Super Peak rate is proposed to be $0.4671 per kWh as compared to the APS-proposed ET-2 off-peak rate of $0.05888 per kWh. Thus, for customers that can move load from the Super Peak period, the savings in the off-peak period would amount to a 20% savings which is significant and should act to incent customers to take action to shift load to the off-peak period. If successful, this type of program could be expanded to other TOU options in future rate cases.

Critical Peak Pricing

Q. Could you please summarize the Company's proposed Critical Peak Pricing ("CPP") Program?

A. To incent customers to reduce load during summer business hours, the Company is proposing a CPP program for General Service Customers, which the Company believes is the best group to target for CPP. The Company believes that this option should be limited at this time to 100 participants for a two-year trial period. The rate would be available to medium, large, and extra large General Service and Water Pumping customers served on rate schedules E-32 M, E-32 L, E-32TOU M, E-32TOU L, E-34, E-35 and E-221. Eligible customers must be capable of reducing usage during critical periods by a minimum of 200 kW and have interval metering.

Q. How would the customers be charged under the rate?

A. This rate schedule would provide a high price for critical hours, as determined by the Company, with one day advance notice. The customer would be charged an additional critical peak price of $0.40 per kWh for consumption during each hour of a "Critical Event", but would be compensated through a discount based on the customer's monthly kWh consumption. As shown on Attachment CAM-2 to Mr. Miessner's testimony, the discounts range from approximately $0.0128 per kWh to $0.149 per kWh, depending on the present rate schedule.

The CPP price and the discount are designed to be revenue neutral for each of the eligible rate classes described above. A customer would have the opportunity to reduce its bills if it reduces usage during the critical hours because the customer would avoid paying the critical peak price, but still receive the monthly discount.

Q. What is a "Critical Event" under APS' proposal?

A. A "Critical Event" may be invoked by the Company for the period from 2 p.m. to 7 p.m., weekdays during June through September, excluding designated holidays. Each "Critical Event" will last the entire 2 p.m. to 7 p.m. period. The critical hours would be limited to 90 hours per year, 5 hours per day, and 18 days per year. A "Critical Event" could be called for any weekday, June through September. The proposed tariff states that a 'Critical Event" could be triggered by severe weather, high load, high wholesale prices, or a major generation or transmission outage as determined by the Company. Customers would be notified of a critical event in advance by 4:00 p.m. the day before by a phone message and/or e-mail.

Q. Why is the Company proposing restrictions on the program?

A. The Company believes that an initial restriction in participation is reasonable given that the program is new to APS and that there has been little or no experience with CPP programs implemented on a large scale basis. In addition there are uncertainties in program success because we do not know the amount of the typical bill savings and the persistence of the customer's load response over time. If successful, the program could be expanded and/or modified.

Q. Should the Company's proposed CPP program be adopted subject to certain modifications?

A. Yes. The Company's proposal to add a new CPP program is a positive step in helping to control peak load. It is targeted to customers that can most likely shed load; it provides an adequate discount to encourage participation (an approximate 22% savings in energy charges); and it is limited in scope so that it can be controlled, evaluated, and improved before it is offered to all customers. However, Staff does believe there are two improvements to this offering that should be implemented.

First, since this is a pilot program, it should be structured so that one can learn as much as possible from it. As proposed, the definition of a "Critical Event" is very open ended, and it is possible that no "Critical Events" would occur while the program is in place. As such, the Company, Commission and customers would learn nothing. To successfully test how customers react to the need for a demand response, one must have actual data. As such, Staff would change the tariff language to state that the Company will invoke a minimum of 6 CPP Events and a maximum of 18 CPP Events per calendar year.

Second, as the Company is proposing to offer CPP to seven different service classes, Staff is concerned that limiting the number of participants to 100 may result in sample sizes that are too small to evaluate. Staff recommends that the number of participants be increased to 200.

Q. Have you prepared tables showing Staff's proposed rate design and typical bills.

A. Staff will file schedules containing comparisons of present and proposed rates and typical bills by January 16, 2009.

OTHER RATE MODIFICATIONS

Q. Please describe the Company's proposed changes to the current Environmental Improvement Surcharge.

A. APS states that the Commission has a real commitment to protecting Arizona's environment, and through its past decisions, the Commission has demonstrated that environmental protection is a compelling public interest. And the Company further states that the use of surcharges is appropriate in order to establish programs that support environmental protection. APS goes on to state that the Environmental Improvement Surcharge ("EIS") currently collects only $4.3 million per year (roughly $2.6 million after tax), and the funds are accounted for as Contributions in Aid of Construction ("CIAC"). APS notes that the projected capital environmental improvement costs for the Cholla Generating Station alone are more than $332 million through 2012. Thus, APS argues that the current EIS does not recover any significant portion of these costs.

APS believes that it is appropriate to expand and expedite the recovery of such environmental costs. APS recommends that the Commission modify the EIS by allowing for a return on investment and a recovery of expenses rather than treating the amounts collected through the EIS surcharge as CIAC. APS indicates that this modification will reduce the up-front dollar rate impact on customers of such environmental improvements.

The Company proposes to implement an adjustor mechanism that would allow the Company to modify the EIS charge on an annual basis as needed to recover actual costs of environmental improvement projects. APS estimates that, if the EIS were to be updated at this time, it would be $0.000179/kWh or only slightly above the current value of $0.00016/kWh. APS does not propose a change to the current EIS and would recover these additional EIS costs in the 2010 EIS filing.

Q. Should the Company's proposed changes to the current EIS be adopted?

A Not as proposed by APS. The Company's position in this case has not changed from its position in the Company's last general rate case. At that time, both RUCO and Staff objected to the implementation of a similar APS proposal for a myriad of reasons. In Decision No. 69663, the Commission stated that APS should be proactive, rather than reactive, on issues of environmental improvement. The Commission expressly recognized APS' arguments that the cost of mandated improvements may increase once those improvements become mandatory, and that implementing the improvements earlier may be less costly and also bring environmental benefits sooner. The Commission found, however, that the method by which APS proposed to seek recovery of those costs was unusual and outside of the normal ratemaking process. Ultimately, the Commission adopted an EIS surcharge set at $.00016 per kWh and further directed that the level of the EIS shall remain in effect until further order by the Commission.

The arguments made by APS in this case are essentially the same as those made in the last case. APS cites the magnitude of the dollars at issue as a reason for changing the EIS surcharge, to an automatic adjustor mechanism. The dollar value of the environmental improvements to the Cholla plant presented by the Company in this case is $332 million. This compares to an amount cited by APS in the prior case of $243 million. But the magnitude of dollars involved is hardly reason enough to justify such a significant departure from the normal ratemaking process. The use of an automatic adjustor mechanism bypasses the normal checks and balances that are part of the regulatory process in a utility base rate case. The trend of ever-expanding automatic adjustment mechanisms has been of concern to the Commission. Moreover, of particular concern to the Commission in APS' last rate case, was the fact that the adjustor mechanism would include forecasted costs as well. No new arguments have been made by APS in the current case and a compelling need for dramatically changing the nature of the EIS, as proposed by APS, has not been demonstrated. Consequently, Staff recommends that APS' proposed modifications to the EIS Surcharge be rejected.

TRANSMISSION COST ADJUSTMENT

Q. Please describe the Company's proposal with respect to the Transmission Cost Adjustment ("TCA").

A. As explained by Company witness Rumolo, the Company proposes that the Federal Energy Regulatory Commission ("FERC") regulated charges be removed from base rates and directly charged to customers through a separate transmission rate schedule, TCA-1. (Rumolo PFT, page 23).

Q. Does APS currently have a TCA?

A. Yes. The current TCA was established as part of a settlement in Docket No. E-01345A-03-0437. Per the terms of the settlement in that case, the TCA was established in order to ensure that any potential direct access customers will pay the same for transmission as standard offer customers. The TCA was limited to recovery of costs associated with changes in the Company's open access transmission tariff ("OATT") or equivalent tariff. The TCA does not take effect until the transmission component of retail rates exceeds the base of $0.000476 per kWh by five percent. When this trigger amount is reached, the Company may file for Commission approval of a TCA rate. Decision No. 69663 required the Company to restructure its retail rates so that the transmission component of the rates reflected the then current OATT charges.

Q. How does the Company propose to change the TCA?

A. The Company's proposals with respect to the TCA and TCA-1 would directly incorporate by reference the Company's then-effective transmission rates, and the TCA would reflect the transmission cost found in base rates today, plus any increased charges in the future. (Rumolo PFT, page 23). When the FERC-regulated transmission rates are changed, APS would re-file the retail transmission rate schedule TCA-1 with the new charges.

Q. Do you agree with the proposed change?

A. No. The proposal to modify the TCA is unnecessary. The current TCA provides the Company the ability to recover its costs. The Company merely needs to file for a change and request Commission approval. The mechanism proposed by the Company would allow the Company to pass through increases to customers without the need for Commission approval. Continued Commission oversight is important. The Commission may elect to not raise rates and simply defer the charge for later recovery. The Commission may want to defer the change for a variety of reasons. Further, automatic adjustment clauses are generally disliked by customers. Automatic adjustment clauses eliminate risk to the utility and reduce the Company's incentive to control costs. Thus, they should only be established with good cause, and no demonstration of that has been made here. The current TCA achieves the correct balance between the needs of the Company and those of the customer, and should not be modified as requested by the Company.

OTHER TARIFF MODIFICATIONS

Q. Are there other rate modifications being proposed by the Company?

A. Yes. The Company has modified EPR-2 purchase rates to reflect updated avoided cost numbers. The purchase rates have been further refined by defined on-peak/off-peak periods, season, and level of firmness. The on-peak/off-peak purchase price has been segregated by TOU periods of 9 a.m.-9 p.m., noon-7 p.m., and 11 a.m.-9 p.m. on weekdays.

The Company also seeks to modify Service Schedules 1, 4, 5, 8, 10 and 15 in a number of respects. These changes clarify existing provisions of the Schedules or make changes to reflect today's business environment. For example, APS is proposing additional language to Section 2.7.6 of Schedule 1 to provide for a security deposit not to exceed "the higher amount of either: one (1) times the customer's maximum monthly bill; or two (2) times the customer's average monthly bill as estimated by Company for the services being provided by Company." This replaces language that limited the deposit to two times the average monthly bill. APS acknowledges that it seeks a variance from a Commission rule enacted many years ago, but argues the rule likely reflected a time when peak monthly bills were closer to the average monthly bill than is presently the case.

Q. Do you agree with those APS-proposed changes?

A. Yes. This seems reasonable to change the rules to reflect conditions that exist today.

Demand Side Management Recovery Mechanism

Q. What is Staff's position concerning Demand Side Management recovery mechanisms?

A. In my direct testimony Staff commented on the reasonableness of the Company's proposed changes to the Demand Side Management ("DSM") adjustor mechanism. In addition, Staff witness Ralph Smith testified that the impacts of Staff's recommendations on the recovery mechanism for DSM related costs are not yet known and would be addressed in Staff's rate design testimony filing (Smith PFT, page 11). In Staff witness Smith's accompanying supplemental testimony, he discusses an APS operating income adjustment related to Demand Side Management and estimated future net revenue losses that APS attributes to DSM. My testimony relates to the policy aspects of the DSM recovery mechanisms and describes how APS is compensated for performing DSM through a performance incentive mechanism that is designed to reward APS only when its DSM programs are successful and result in energy or demand savings.

Staff strongly supports steps to encourage energy conservation and that goes to DSM programs as well. That said, however, the DSM lost revenue cost recovery mechanism covers a wide spectrum of possibilities. At one extreme is complete, or full, revenue decoupling mechanism where the utility is protected from any variations from projected revenue forecasts between rate cases regardless of the reason. At the other end of the spectrum is where a utility is ordered to implement energy conservation measures to avoid building, or buying, generation resources and no compensation is given. APS' current DSM programs include a performance incentive mechanism that rewards the Company only when its DSM programs are successful and result in energy or demand savings. Thus, APS' current program strikes the right balance. Additionally, Decision No. 67744 in a previous APS case adopted a Settlement Agreement that provided for a DSM performance incentive. As noted by the Commission in Decision No. 69663, under that Settlement Agreement, APS was not allowed to recover net lost revenues.

In this case, with its DSM income adjustment, the Company is attempting to recover estimated future net lost revenues that APS attributes to DSM. One must remember that every time rates are re-set, the Company is made whole for their so called lost revenues. As Staff noted in my initial testimony the current DSM adjustor mechanism gives APS 10% of program expenditures each year. Recovery of estimated future lost revenues and a performance incentive mechanism are two different and mutually exclusive means to compensate the utility for performing DSM. The Company has agreed to a performance incentive as part of a settlement that balanced the interests of all parties. Thus, the utility is already compensated for performing DSM. Accordingly, APS' request for recovery of estimated future net lost revenues attributed to DSM should be rejected.

Q. Does this conclude your rate design testimony?

A. Yes, it does, except that Staff will file schedules containing comparisons of present and proposed rates and typical bills by January 16, 2009.

Exhibit__(FWR-2)

APS Response to Staff Discovery Request 22.7

ARIZONA CORPORATION COMMISSION
STAFF'S TWENTY-SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY,
REGARDING THE AMENDED APPLICATION TO APPROVE RATE SCHEDULES
DESIGNED TO DEVELOP A JUST AND REASONABLE RATE OF RETURN
E-01345A-08-0172
NOVEMBER 14, 2008

Staff 22.7 RE: Delizio Testimony pages 15-16, are there any specific workpapers that tie the results of the cost of service study to the revenue allocation? If so, please provide them. If not, for each service class and each rate schedule (e.g. E-32, 21-100 kW) please provide an explanation of how the results of the cost of service study are used in your recommended revenue allocation.

Response: Yes. The attached table provides a comparison between cost of service revenue deficiency for each rate class and the proposed revenue increase. The cost of service provides a guide for revenue allocation – lower performing rates in terms of revenue deficiency or rate of return received a relatively higher proposed increase and visa versa. However, the proposed increases are not designed to return each rate class to cost parity, but rather to move in that direction. Other objectives considered in the revenue allocation process include, for example, (1) preserving rate stability and avoiding rate shock for any rate class, (2) reducing, but not eliminating, the return differential between general service and residential revenue classes, and (3) preserving consistency between time-of-use rates and other rate options. The attachment is provided in Excel format as APS13779.

Witness: Gregory DeLizio

ARIZONA PUBLIC SERVICE COMPANY
ANALYSIS OF BASE REVENUES BY DETAILED CLASS
TEST YEAR ENDING DECEMBER 31, 2007 ADJUSTED

Customer Classification and Current Rate Designation	Average Number of Customers	Adjusted MWh Sales	Base Revenues under Present Rates ($000)	Proposed Rate Designation	Proposed: Base Revenues ($000)	Proposed: Transmission Revenues ($000)	Proposed: Total Revenues ($000)	Increase - Base Rates: Amount ($000)	Increase - Base Rates: %	PSA Impacts ($000)	Bill Impacts: Net of PSA Impacts ($000)	Bill Impacts: Net of PSA Impacts %	COSS Revenue Requirement Deficiency
								(I) - (E)	(J) / (E)				
Residential													
E-10	62,712	526,327	57,215	E-12	63,903	2,717	66,620	9,405	[illegible]	(3,100)	6,305	11.02%	[illegible]
E-12	447,532	4,053,590	442,588	E-12	494,535	20,785	515,320	72,732	[illegible]	(23,880)	48,852	11.04%	[illegible]
EC-1	17,348	343,675	32,443	ECT-1R	36,400	1,751	38,151	5,708	[illegible]	(2,024)	3,684	11.36%	[illegible]
ET-1	353,442	6,181,124	594,946	ET-1	667,843	31,529	699,372	104,426	[illegible]	(36,411)	68,015	11.43%	[illegible]
ECT-1R	48,110	1,418,894	122,822	ECT-1R	138,661	7,251	145,912	23,090	[illegible]	(8,358)	14,732	11.99%	[illegible]
ET-2	29,822	724,545	70,808	ET-2	79,523	3,712	83,235	12,427	[illegible]	(4,268)	8,159	11.52%	[illegible]
ECT-2	7,046	308,660	26,213	ECT-2	29,488	1,587	31,075	4,862	[illegible]	(1,818)	3,044	11.61%	[illegible]
Total Residential	966,012	13,556,815	1,347,035		1,510,353	69,332	1,579,685	232,650	[illegible]	(79,859)	152,791	11.34%	[illegible]
General Service													
E-20	329	34,392	3,267	E-20	3,631	296	3,927	660	[illegible]	(203)	457	13.99%	[illegible]
E-21	20	1,037	123	E-32TOU	139	6	145	22	[illegible]	(6)	16	13.01%	[illegible]
E-22	13	2,622	308	E-32TOU	350	18	368	60	[illegible]	(15)	45	14.61%	[illegible]
E-23	84	19,246	1,749	E-32TOU	1,977	76	2,053	304	[illegible]	(113)	191	10.92%	[illegible]
E-24	38	111,865	7,722	E-32TOU	8,699	317	9,016	1,294	[illegible]	(659)	635	8.22%	[illegible]
E-30	4,618	5,648	1,134	E-30	1,334	12	1,346	212	[illegible]	(33)	179	15.78%	[illegible]
E-32 (0 to 20 KW)	89,228	1,435,595	172,703	E-32 (0 to 20 KW)	198,866	6,087	204,953	32,250	[illegible]	(8,457)	23,793	13.78%	[illegible]
E-32 (21 to 100 KW)	18,248	2,727,984	272,756	E-32 (21 to 100 KW)	303,734	14,223	317,957	45,201	[illegible]	(16,070)	29,131	10.68%	[illegible]
E-32 (101 to 400 KW)	4,058	3,468,621	292,377	E-32 (101 to 400 KW)	325,073	14,730	339,803	47,426	[illegible]	(20,433)	26,993	9.23%	[illegible]
E-32 (401+ kw)	1,006	4,067,019	306,941	E-32 (401+ kw)	340,594	14,666	355,260	48,319	[illegible]	(23,958)	24,361	7.94%	[illegible]
E-32TOU	64	76,981	5,526	E-32TOU	6,349	75	6,424	898	[illegible]	(453)	445	8.05%	[illegible]
E-34	39	1,282,858	84,806	E-34	94,544	4,280	98,824	14,018	[illegible]	(7,557)	6,461	7.62%	[illegible]
E-35	20	1,554,899	89,217	E-35	101,039	4,857	105,896	16,679	[illegible]	(9,160)	7,519	8.43%	[illegible]
E-40	1	1	1	E-40	2	-	2	1	[illegible]	-	1	11.60%	[illegible]
E-51	1	8,748	602	E-56	698	29	727	125	[illegible]	(52)	73	12.13%	[illegible]
E-55	1	8,170	936	E-56	1,035	32	1,067	131	[illegible]	(48)	83	8.87%	[illegible]
Total General Service	117,768	14,805,686	1,240,168		1,388,064	59,704	1,447,768	207,600	[illegible]	(87,217)	120,383	9.71%	[illegible]
Irrigation and Water Pumping													
E-38, E-38-8T, E-38TOW	71	5,658	430	E-221, E-221-8T, E-221TOW	443	26	469	39	[illegible]	(33)	6	1.40%	[illegible]
E-221, E-221-8T, E-221TOW	1,397	332,112	24,946	E-221, E-221-8T, E-221TOW	25,918	2,110	28,028	3,082	[illegible]	(1,956)	1,126	4.51%	[illegible]
Total Irrigation	1,468	337,770	25,376		26,361	2,136	28,497	3,121	[illegible]	(1,989)	1,132	4.46%	[illegible]
Outdoor Lighting													
E-58	600	31,868	8,719	E-58	10,271	135	10,406	1,687	[illegible]	(188)	1,499	17.19%	[illegible]
E-59, City Streetlight Contracts	243	82,185	7,635	E-59, City Streetlight Contrac	8,773	348	9,121	1,486	[illegible]	(484)	1,002	13.12%	[illegible]
E-67	189	3,944	178	E-67	198	17	215	37	[illegible]	(23)	14	7.87%	[illegible]
Contract	40	10,753	840	Contract	957	45	1,002	162	[illegible]	(63)	99	11.79%	[illegible]
Total Outdoor Lighting	1,072	128,750	17,372		20,199	545	20,744	3,372	[illegible]	(758)	2,614	15.05%	[illegible]
Dusk to Dawn Lighting Service		26,102	7,496		8,836	111	8,947	1,451	[illegible]	(154)	1,297	17.30%	[illegible]
Total Sales to Ultimate Retail Customers	1,086,320	28,855,123	2,637,447		2,953,813	131,828	3,085,641	448,194	[illegible]	(169,977)	278,217	10.55%	[illegible]

EXHIBIT (FWR-3)

TABLE SHOWING STAFF AND COMPANY PROPOSED REVENUE ALLOCATION

Exibit__(FWR-3)

Arizona Public Service
Docket No. E-01345A-08-0172

Staff and Company Proposed Revenue Allocation

				Company Proposal					Staff Proposal					
Customer Classification and Current Rate Designation	Proposed Rate Designation		Adjusted Present Revenue ($)	Adjusted Proposed Revenue ($)	Transmission Revenue ($)	Total Proposed Revenue ($)	Increase ($)	Percent increase	Total Present Revenues net of E-3 & E-4	Staff Prposed Increase	E-3, E-4 Revenues	Staff Total Proposed Revenue	Increase	Percent Increase
Residential														
E10	E-12		57,214,435	63,903,558	2,716,910	66,620,468	9,406,033	16.44%	53,743,948	6,352,777	3,470,487	63,567,212	6,352,777	11.10%
E12	E-12		442,587,367	494,535,672	20,785,346	515,321,018	72,733,651	16.43%	422,287,335	49,916,268	20,300,032	492,503,635	49,916,268	11.28%
EC-1	ECT-1R		32,442,990	36,399,749	1,751,482	38,151,232	5,708,242	17.59%	32,070,829	3,790,917	372,161	36,233,907	3,790,917	11.68%
ET-1	ET-1		594,945,870	887,842,852	31,528,547	699,371,199	104,425,329	17.55%	578,443,018	68,374,575	16,502,852	663,320,445	68,374,575	11.49%
ECT-1R	ECT-1R		122,821,690	138,660,904	7,250,921	145,911,825	23,090,135	18.80%	121,832,838	14,401,191	988,852	137,222,881	14,401,191	11.73%
ET-2	ET-2		70,807,787	79,523,220	3,711,971	83,235,190	12,427,403	17.55%	68,963,250	8,151,767	1,844,537	78,959,554	8,151,767	11.51%
ECT-2	ECT-2		26,212,827	29,487,693	1,587,272	31,074,965	4,862,138	18.55%	25,935,838	3,065,733	276,989	29,278,560	3,065,733	11.70%
		Total Residential	1,347,032,966	1,510,353,447	69,332,449	1,579,685,896	232,652,930	17.27%	1,303,277,056	154,053,228	43,755,910	1,501,086,194	154,053,228	11.44%
General Service														
E-20	E-20		3,267,158	3,630,840	296,217	3,927,057	659,899	20.20%	3,267,158	386,193		3,653,351	386,193	11.82%
E-30	E-30		1,133,744	1,333,645	12,098	1,345,743	211,999	18.70%	1,133,744	134,014		1,267,758	134,014	11.82%
E-34	E-34		84,805,810	94,544,275	4,279,809	98,824,084	14,018,274	16.53%	84,805,810	10,024,429		94,830,239	10,024,429	11.82%
E-35	E-35		89,217,103	101,038,587	4,856,952	105,895,539	16,678,436	18.69%	89,217,103	10,545,864		99,762,967	10,545,864	11.82%
E-40	E-40		1,305	1,542	6	1,548	243	18.62%	1,305	154		1,459	154	11.82%
E-51	E-56		602,059	698,861	28,286	727,147	125,088	20.78%	602,059	71,166		673,225	71,166	11.82%
E-55	E-56		936,310	1,035,064	32,376	1,067,440	131,130	14.01%	936,310	110,676		1,046,986	110,676	11.82%
New E-32 Rates														
E-21	E-32TOU		123,129	139,215	6,477	145,692	22,563	18.32%	123,129	14,554		137,683	13,535	
E-22	E-32TOU		308,204	349,675	18,464	368,139	59,935	19.45%	308,204	36,431		344,635	24,487	
E-23	E-32TOU		1,749,448	1,976,532	75,918	2,052,450	303,002	17.32%	1,749,448	206,793		1,956,241	180,140	
E-24	E-32TOU		7,721,782	8,698,642	316,872	9,015,514	1,293,732	16.75%	7,721,782	912,749		8,634,531	805,678	
E-32 (0 to 20 KW)	E-32 (0 to 20 KW)		172,702,526	198,866,184	6,086,630	204,952,814	32,250,288	18.67%	172,702,526	20,414,218		193,116,744	24,911,744	
E-32 (21 to 100 KW)	E-32 (21 to 100 KW)		272,755,575	303,734,186	14,222,605	317,956,791	45,201,216	16.57%	272,755,575	32,240,940		304,996,515	31,721,087	
E-32 (101 to 400 KW)	E-32 (101 to 400 KW)		292,377,288	325,073,305	14,729,680	339,802,985	47,425,697	16.22%	292,377,288	34,560,315		326,937,603	33,231,801	
E-32 (401-999 kw)	E-32 (401-999 kw)		306,941,087	340,594,113	14,666,186	355,260,299	48,319,212	15.74%	306,941,087	36,281,821		343,222,908	33,689,255	
E-32 TOU	E-32 TOU		5,526,429	6,348,751	74,684	6,423,435	897,006	16.23%	5,526,429	653,249		6,179,678	743,343	
		Subtotal E-32 Rates	1,060,205,468	1,185,780,602	50,197,517	1,235,978,119	175,772,851	16.58%	1,060,205,468	125,321,070		1,185,526,538	125,321,070	11.82%
		Total General Service	1,240,168,957	1,388,063,417	59,703,261	1,447,766,678	207,597,720	16.74%	1,240,168,957	146,593,566		1,386,762,524	146,593,566	11.82%
Irrigation and Water Pumping														
E-38	E-221, E-221-8T, E-221TOW		430,321	443,099	26,112	469,212	38,891	9.04%	430,321	50,866		481,187	50,866	11.82%
E-221	E-221, E-221-8T, E-221TOW		24,945,866	25,918,207	2,109,656	28,027,863	3,081,998	12.35%	24,945,866	2,948,714		27,894,579	2,948,714	11.82%
		Total Irrigation	25,376,187	26,361,306	2,135,769	28,497,075	3,120,889	12.30%	25,376,187	2,999,580		28,375,766	2,999,580	11.82%
Outdoor Lighting														
E-58	E-58		8,719,188	10,271,074	135,275	10,406,350	1,687,162	19.35%	8,719,188	1,030,647		9,749,835	1,030,647	11.82%
E-59	E-59		7,635,291	8,772,681	348,078	9,120,759	1,485,468	19.46%	7,635,291	902,526		8,537,817	902,526	11.82%
E-67	E-67		178,381	198,109	16,646	214,756	36,375	20.39%	178,381	21,085		199,466	21,085	11.82%
Contract 12	Contract 12		840,117	957,363	45,401	1,002,764	162,647	19.36%	840,117	99,306		939,423	99,306	11.82%
		Total Outdoor Lighting	17,372,977	20,199,228	545,401	20,744,629	3,371,651	19.41%	17,372,977	2,053,564		19,426,542	2,053,564	11.82%
Dusk to Dawn														
E-47			7,496,002	8,835,659	110,813	8,946,472	1,450,470	19.35%	7,496,002	886,061		8,382,063	886,061	11.82%
		Total Dusk to Dawn	7,496,002	8,835,659	110,813	8,946,472	1,450,470		7,496,002	886,061		8,382,063	886,061	11.82%
		Grand Total	2,637,447,089	2,953,813,057	131,827,692	3,085,640,750	448,193,660	16.99%	2,593,691,179	306,586,000		2,944,033,089	306,586,000	11.62%